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DRILLING FLUID AND METHOD FOR ENHANCED SUSPENSION

Inventors:

JEFF MILLER
Houston, Texas

and

JEFF KIRSNER
Houston, Texas

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RELATED APPLICATION

[0001] This application is a continuation-in-part of United States Patent Application Serial No. 10/292,124, of Jeff Kirsner, et al., filed November 12, 2002, and entitled "Invert Drilling Fluids and Methods of Drilling Boreholes", pending, which is a continuation-in-part of United States Patent Application Serial No. 10,175,272, filed June 19, 2002, pending, which is a continuation-in-part of United States Patent Application Serial No. 09/929,465, filed August 14, 2001, pending, and International Patent Application Nos. PCT/US00/35609 and PCT/US00/35610, both filed December 29, 2000, and pending in the United States as United States Patent Application Serial Nos. 10/432,787 and 10/432,786 respectively, the content of each of which is incorporated herein by reference.

BACKGROUND OF THE INVENTION

1. Field of the Invention

[0002] The present invention relates to compositions and methods for drilling boreholes in subterranean formations, particularly hydrocarbon bearing formations, and to drilling fluids for use in such drilling operations. More particularly, the present invention relates to oil and synthetic fluid based drilling fluids comprising invert emulsions, and drilling fluid additives that enhance suspension characteristics of such drilling fluids.

2. Description of Relevant Art

[0003] A drilling fluid or mud is a specially designed fluid that is circulated through a wellbore as the wellbore is being drilled to facilitate the drilling operation. The various functions of a drilling fluid include removing drill cuttings from the wellbore, cooling and lubricating the drill bit, aiding in support of the drill pipe and drill bit, and providing a hydrostatic head to

maintain the integrity of the wellbore walls and prevent well blowouts. Specific drilling fluid systems are selected to optimize a drilling operation in accordance with the characteristics of a particular geological formation. As used herein, the term "drilling fluid" shall be understood to include fluids used in drilling, and/or cementing, casing and/or other completion operations downhole.

[0004] Oil or synthetic fluid-based muds are normally used to drill swelling or sloughing shales, salt, gypsum, anhydrite or other evaporate formations, hydrogen sulfide-containing formations, and hot (greater than about 300 degrees Fahrenheit ("° F") holes, but may be used in other holes penetrating a subterranean formation as well. Unless indicated otherwise, the terms "oil mud" or "oil-based mud or drilling fluid" shall be understood to include synthetic oils or other synthetic fluids as well as natural or traditional oils, and such fluids shall be understood to comprise invert emulsions. As used herein, the term "synthetic fluid" has the meaning generally known and used by the oil and gas drilling industry. Generally, the term "synthetic fluid" means a material produced by the chemical reaction of specific purified chemical feedstock as opposed to traditional base fluids such as diesel and mineral oil which are derived from crude oil solely through physical separation processes, e.g., fractionation, distillation, and minor processes such as cracking and hydroprocessing.

[0005] Oil-based muds and synthetic-fluid based muds used in drilling typically comprise: a base oil or synthetic fluid comprising the external phase of an invert emulsion; a saline, aqueous solution (typically a solution comprising about 30% calcium chloride) comprising the internal phase of the invert emulsion; emulsifiers at the interface of the internal and external phases; and other agents or additives for suspension, weight or density, oil-wetting, fluid loss or filtration control, and rheology control. Such additives commonly include

organophilic clays and organophilic lignites. See H.C.H. Darley and George R. Gray, Composition and Properties of Drilling and Completion Fluids 66-67, 561-562 (5^{th} ed. 1988). An invert emulsion-based drilling fluid may commonly comprise between about 50:50 to about 95:5 by volume oil phase to water phase, or synthetic fluid phase to water phase. An all oil mud simply comprises 100% liquid phase oil by volume; that is, there is no aqueous internal phase.

[0006] Invert emulsion-based muds or drilling fluids (also called invert drilling muds or invert muds or fluids) comprise a key segment of the drilling fluids industry. However, increasingly invert emulsion-based drilling fluids have been subjected to greater environmental restrictions and performance and cost demands. With space at some well sites limited, such as on offshore platforms, and with increasing costs of transport of materials to a wellsite, there is industry wide interest in, and on-going need for, more efficient drilling fluid additives and for drilling fluids which can be formulated and maintained with minimal or fewer additives than common with prior art drilling fluids, while still affording environmental and economical acceptance.

SUMMARY OF THE INVENTION

[0007] An improved and more efficient invert emulsion based drilling fluid and method are disclosed for use in drilling boreholes in subterranean formations, particularly hydrocarbon bearing formations.

[0008] The drilling fluid of the invention comprises a polymer additive that imparts favorable suspension characteristics and shear thinning viscosity to the drilling fluid without unduly or excessively enhancing the viscosity of the fluid. That is, the present invention provides a drilling fluid with improved suspension characteristics (or properties) that has not

been "thickened" (i.e., had its viscosity increased) to the point that the equivalent circulating density (ECD) of the fluid has been negatively or detrimentally increased.

[0009] Moreover, the polymer additive is particularly advantageous when applied according to the preferred method of the invention because the additive generally eliminates the need for two other additives commonly used in drilling fluids—fluid loss or filtration control additives and clays. This advantage of the present invention is particularly appreciated for use with offshore wells where only limited or relatively little space is available on offshore platforms for storage of drilling fluid components. The polymer additive itself imparts fluid loss control to the drilling fluid of the invention in addition to providing suspension characteristics. Moreover, the additive imparts suspension characteristics to the drilling fluid without the addition of or presence of organophilic clays (also called "organo-clays") so commonly used and traditionally believed by the oil and gas drilling industry to be necessary for suspension of drill cuttings. Thus, a drilling fluid of the invention is not dependent on organophilic clays to obtain suspension of drill cuttings. Any characterization of the drilling fluid herein as "clayless" shall be understood to mean lacking organophilic clays. Further, the rheological properties of the drilling fluid of the invention remain stable over a broad temperature range even after exposure to high temperatures.

[0010] Another advantage of the present invention is the ability the invention affords to formulate and use such a useful, serviceable and efficient fluid that meets stringent environmental compatibility restrictions commonly found in sensitive environmental zones such as the Gulf of Mexico.

[0011] A drilling fluid of the invention may be generally identified by reference to laboratory tests measuring suspension characteristics of a fluid, such as Stress Build Index (SBI)

(or Stress Build Function), Gel Progression Index (GPI), and yield stress (or Tau zero or Tau 0) used in calculating SBI. These tests are generally conducted as described herein on laboratory-mud fluids. Generally, a laboratory prepared fluid of the present invention as measured at 120°F will have a preferred yield stress of less than about 15, an SBI in the preferred range of about 1 to about 2, and a GPI in the preferred range of about 0 to about 10, indicating progressive gel behavior. A drilling fluid of the invention also indicates good filtration control in a high temperature, high pressure (HTHP) test.

[0012] Although the invention is characterized primarily through identifying characteristics or features of a synthetic fluid-based drilling fluid that has suspension characteristics approximating or approaching those of an aqueous-based drilling fluid containing xanthan gum, it is believed that the advantages of the present invention may be realized with a polymer additive that is preferably a co-polymer or terpolymer, comprising mostly hydrophobic monomers with a smaller amount of hydrophilic monomers. To be considered hydrophilic, the monomer should generally have a solubility of above about 3 % by weight in water at room temperature, and to be considered hydrophobic, the monomer should generally have a solubility of below about 3% by weight in water at room temperature (about 20°C). The polymer preferably should be substantially linear and substantially free of aromatic hydrocarbons. A most preferred polymer for comprising the additive of the invention is the emulsion copolymer of 2-ethylhexyl acrylate and acrylic acid in about a 99:1 ratio, although ratios with higher quantities of acrylic acid have been found effective. For example, 85:15 (2-ethylhexyl acrylate to acrylic acid) has been found acceptable even at temperatures as high as about 350°F.

[0013] Any oil or synthetic fluid base suitable for comprising a drilling fluid or for use in a drilling fluid may be used in the drilling fluid of the invention.

[0014] The methods of the invention provide or employ the improved drilling fluids of the invention for improved drilling of boreholes in subterranean formations.

BRIEF DESCRIPTION OF THE DRAWING

[0015] Figure 1 is a graph comparing the gel strength over time of three different fluids, one being an example fluid of the invention, one being an aqueous fluid thickened with xanthan gum, and one being a synthetic fluid containing organoclays.

DETAILED DESCRIPTION OF PREFERRED EMBODIMENTS

[0016] The drilling fluid of the present invention is an oil- or synthetic fluid-based invert emulsion drilling fluid comprising a polymer additive whose effects in the drilling fluid rival those of xanthan gum in an aqueous based fluid. That is, the drilling fluid of the invention provides excellent suspension of weight material and drill cuttings, shear-thinning viscosity, and highly progressive gellation. The fluid also provides good filtration control as measured by a high temperature, high pressure (HTHP) test. Moreover, the properties of the fluid remain stable after exposure to high temperatures. The fluid also does not generally require additives to alter the fluid's cold-temperature properties.

[0017] When formulated as preferred, the drilling fluid of the invention is efficient and relatively simple, comprising fewer components than typical of commercially available oil or synthetic fluid-based drilling fluids. This characteristic allows the fluid of the invention to be economical and particularly favored for use in offshore wells, where offshore platforms have only limited or relatively little space for storing drilling fluid components. That is, when formulated as preferred, the drilling fluid of the invention may comprise as few components as a synthetic fluid base and an aqueous solution for making the invert emulsion, one or more

emulsifiers, an optional neutralizing agent such as lime, the polymer additive of the invention, and weighting agents. See Tables 4, 5 and 6.

[0018] The drilling fluid of the invention preferably has as its base one or more environmentally acceptable oil or synthetic fluids, such as, for example, the esters, olefins, paraffins, and ester blends taught in United States Patent Application Publication No. 2003/0036484, of Jeff Kirsner, et al., published February 20, 2003, and incorporated herein by reference. Olefins and paraffins are generally preferred for best performance according to the invention. Examples of preferred commercially available synthetic fluids suitable for the base of the drilling fluids of the present invention are LE BASE™, and SF BASE™, both available from Halliburton Energy Services, Inc. in Houston, Texas. However, the particular drilling fluid base selected will depend at least in part on the intended location of use of the fluid. Selection criteria for a base fluid include, for example, any government environmental compatibility restrictions, as well as considerations related to subterranean formation characteristics (e.g., temperatures, depths, types of formation clays, etc.), physical location of the well on or off shore, and costs. For example, in the Gulf of Mexico, only certain fluids meet standards provided by the United States government for use in drilling offshore wells and so the base fluid for purposes of the present invention must be such a fluid if planned for use in the Gulf of Mexico.

[0019] The drilling fluid of the invention generally does not need viscosifiers or additional suspension agents and generally does not need or require for its effectiveness fluid loss control agents or filtration control additives. This characteristic applies over a broad temperature range, and is particularly applicable at temperatures as low as about 40°F, a typical temperature encountered in deepwater offshore operations or in cold climates, as well as at higher temperatures, such as 120°F, as demonstrated by test data discussed below. The fluid has

been found to have acceptable characteristics at temperatures as low as 32 °F and as high as 350 °F and is believed to be effective at even higher temperatures. The polymer additive of the invention imparts suspension characteristics to the fluid and also imparts fluid loss control. Further, the drilling fluid of the invention does not generally exhibit problematic sag.

[0020] Laboratory tests may be used to distinguish drilling fluids of the invention from clay-suspended (i.e., traditional) fluids. The tests discussed here were conducted with laboratory prepared fluids having a volume ratio of synthetic fluid to water of about 70:30, 75:25, 80:20, or 85:15. Other ratios, although less common, could also be used. The tests include yield stress, Stress Build Index (SBI) (or Stress Build Function), and Gel Progression Index (GPI) or how well the gel strength increases over time. The SBI and GPI values are indicative of suspension capabilities and the value for yield stress (Tau zero) is used in determining the SBI. The tests results should indicate progressive gel behavior.

[0021] Yield stress (Tau zero) is the torque required to just start a system moving from rest. This point is selected for measurement because low shear rates remove inertial effects from the measurement and thus enable a truer measure of yield stress than measurements taken at other points. Generally, laboratory prepared drilling fluids of the present invention at these laboratory conditions/specifications will have a yield stress of less than about 15, preferably less than about 10, with variances depending on the fluids used for the oil or synthetic base and the particular polymer additive of the invention.

[0022] SBI indicates structure building tendencies normalized for initial yield stress (Tau zero). SBI also effectively normalizes for mud weight, since generally higher weight fluids have higher Tau zero values. Tau zero is related to SBI by the following equation:

$$\text{SBI} = (\text{10 minute gel strength} - \text{Tau zero})/\text{Tau zero}$$

where SBI is the measure of how much gel structure is built in ten minutes relative to the yield stress or Tau zero. A FANN® 35 viscometer, a standard six speed oilfield rheometer, was used in measuring SBI in the experiments discussed below, but other rheometers may be used. Generally, laboratory prepared drilling fluids of the present invention will have a SBI (or SBF10m) of greater than 1 as measured at 120°F, and preferably an SBI in the range of about 1 to about 2.

[0023] GPI, i.e., a measure of how well the gel strength increases over a ten-minute time interval, is calculated in accordance with the following equation:

$$\text{GPI} = (\text{10 minute gel strength}/\text{10 second gel strength}) - 1$$

Generally, laboratory prepared drilling fluids of the present invention will have a GPI of about 0.6 or greater, or preferably in the range of about 0.5 to about 2, as measured at 120°F. Guidelines for measuring such 10 minute gel strength (and similar 10 second gel strength, measured in the same manner as the 10 minute gel strength except over a smaller period of time) are provided in American Petroleum Institute (API) Specification 13B-2, Section 4.3, Third Edition, February 1998.

[0024] Field-based fluids (as opposed to laboratory fluids or muds) may yield varying results in the laboratory tests above because of the presence of other fluids, subterranean formation conditions, etc. While some organo-clay may enter the fluids in the field, for example, due to mixing of recycled fluids with the fluids of the invention, the fluids of the invention are tolerant of such clay in low quantities. The fluids of the invention, however, are expected to behave more like traditional drilling fluids when organo-clays are present in quantities approaching those typical of traditional drilling fluids comprising organo-clays for suspension characteristics. That is, the advantages of the present invention become reduced or lost upon the

addition of such significant quantities of organo-clays. In the test examples below, GELTONE® II additive used is a common organo-clay.

[0025] A preferred polymer additive of the invention, called "EXP A1" in the test data discussed below, is an emulsion copolymer of 2-ethylhexyl acrylate and acrylic acid, prepared as described in United States Patent No. 4,670,501, issued June 2, 1987 to Dymond et al., and a continuation-in-part of that patent, United States Patent No. 4,777,200, issued October 11, 1988 to Dymond et al., both of which are incorporated herein by reference (the Dymond patents). A formulation having a 2-ethylhexyl acrylate to acrylic acid ratio of about 99:1 is most preferred, although other ratios may be used, provided that the quantity of hydrophobic monomers on the polymer exceed the quantity of hydrophilic monomers. At very high temperatures, such as about 300°F to about 350 °F or higher, it is likely that some acrylate will hydrolyze to acrylic acid, raising the content of acrylic acid in the ratio. Ratios as high in acrylic acid as 15%, for example, 85:15 2-ethylhexyl acrylate to acrylic acid, have been found acceptable at these temperatures. See Table 7 discussed further below. Alternatively, vinyl neodecanoate may be effectively substituted for 2-ethylhexyl acrylate in formulating the polymer for the present invention.

[0026] Although such Dymond polymers may be generally useful as polymer additives in the present invention, the present invention is not limited to the use of such polymers and some of such polymers may perform significantly better according to the present invention than others. Key to ascertaining polymer additive(s) suitable for the present invention are the results of laboratory tests measuring suspension characteristics imparted by the polymer to samples of laboratory prepared drilling fluids formulated without organo-clays according to the present invention.

[0027] The Dymond patents teach polymeric compositions for thickening "water-immiscible liquid," and that particularly good thickening effects may be achieved when inorganic particulate solids such as organophilic bentonite or other clays are added to the liquid.

[0028] In contrast, the present invention is directed not to "thickening" fluids but to enhancing the suspension characteristics of drilling fluid without significantly "thickening" the fluid, or more specifically, without increasing the viscosity of the fluid such that the fluid's equivalent circulating density increases significantly downhole.

[0029] Moreover, notwithstanding the teaching of the Dymond patents and the accepted and customary practice in the industry that advantages may be achieved by including organophilic bentonite and other clays with the polymers, the present invention unexpectedly provides a formulation that yields superior results in enhancing the suspension characteristics of an oil- or synthetic fluid-based drilling fluid without such clays. Further, the formulation of the invention achieves these superior results without causing undue viscosity while also providing shear-thinning properties. Additionally, as previously noted, the present invention provides a drilling fluid that achieves superior rheology without need for filtration control additives or fluid loss control additives, notwithstanding the use of such additives in the teachings of the Dymond patents.

[0032] The advantages of the present invention are demonstrated by the test data below.

Experimental

[0033] An experiment was conducted to compare a drilling fluid formulated according to the teachings of the Dymond patents (Sample "A") with an example drilling fluid formulated according to the present invention (Sample "B") using mineral oil, the base used in Sample "A" according to the teachings of the Dymond patents. That is, specifically, the recipe for a drilling

fluid of Example 3 in the Dymond patents was used for Sample "A." Sample "B" was similarly prepared but without fluid loss control agent. Both Samples "A" and "B" were prepared without clays. The Dymond patents failed to specify temperature(s) used so temperatures typical for offshore wells, where the present invention is particularly advantageous, were used. Both samples had an active polymer content of 40%, as 12.5 lb/bbl of polymer yields 5 pounds per barrel active polymer in this experiment. The formulations and the rheological properties of the samples are shown in Table 1.

TABLE 1

(12.1 lb/gal Fluids; 79/21 OWR with 220,000 ppm WPS)

Sample	Blank	A		B	
HDF-2000™ light mineral oil, bbl	0.640	0.640		0.640	
Freshwater, bbl	0.085	0.085		0.085	
11.6 lb/gal $CaCl_2$ brine, bbl	0.087	0.087		0.087	
EZ MUL NT™ emulsifer, lb	7	7		7	
DURATONE® HT fluid loss agent, lb	10	10		-	
Lime, lb	5	5		5	
DRILTREAT™ wetting agent, lb	1	1		1	
BAROID® weighting agent, lb	243	243		243	
EXP A1 polymer, lb	-	12.5		12.5	
After adding EXP A1 polymer, the samples were mixed 30 minutes					
Temperature, °F	120	40	120	40	120
Plastic Viscosity, cP	16*	105*	33	69	29
Yield Point, lb/100 ft^2	1	81	17	25	24
10 Sec gel, lb/100 ft^2	2	18	8	7	10
10 Min gel, lb/100 ft^2	2	18	16	11	24
30 Min gel, lb/100 ft^2	-	19	20	15	26
Electrical stability, v	411	-	924	-	810
HTHP filtrate @ 250°F, ml	-	1.0		3.8	
FANN® 35 Viscometer Dial Readings					
600 rpm	33	291	83	163	82
300 rpm	17	186	50	94	53
200 rpm	13	142	39	69	43
100 rpm	7	90	26	41	30
6 rpm	1	22	9	9	11
3 rpm	1	18	8	7	10
Tau zero, lb/100 ft^2	0.3	10.3	7.3	5.4	8.2
n (flow index)	0.91	0.69	0.80	0.83	0.70
K (consistency index)	0.06	2.45	0.31	0.53	0.62
GPI	0.0	0.0	1.0	0.6	1.4
SBI	6.4	0.8	1.2	1.0	1.9

*Indicates settling of barite observed after measuring properties.
Sample A had some fluid solidifying while measuring properties at 40°F.
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[0034] The test data in Table 1 indicates that Sample "B," an example fluid of the present invention prepared with mineral oil (as used in the Dymond patents) instead of preferred synthetic fluid, had acceptable filtration properties as measured by the high temperature, high

pressure filtrate (HTHP) test at 250°F, without inclusion of a fluid loss control agent in the formulation. HTHP filtrate values of 1.0 ml (Sample "A") and 3.8 ml (Sample "B") are both low values for this test, which indicates that both samples would provide effective control of fluid loss to the formation. However, at lower temperatures (40°F), Sample "A" was too viscous to be used effectively as a drilling fluid, whereas Sample "B" showed excellent properties at both temperatures tested (40°F and 120°F). Moreover, the Tau zero value and the GPI and SBI values for Sample "B" were higher at 120°F than for Sample "A." Additionally, the consistency index, K, for Sample "A" at 40°F was excessive, while the value for Sample "B" at 40°F was low, even slightly lower than the consistency value for Sample "B" at 120°F.

[0035] Thus, this test data demonstrates that even mineral oil-based invert emulsion drilling fluids prepared according to the present invention performed superior to the drilling fluids taught by the Dymond patents.

[0036] Additional experiments are reported in Tables 2 and 3, showing formulations and rheological properties for samples prepared like Sample "B" of Table 1 but with more refined oil or synthetic fluids preferred according to the present invention rather than with mineral oil. This data indicates the advantages of the present invention as discussed above.

TABLE 2

(12.1 lb/gal Fluids; 79/21 OWR with 220,000 ppm WPS)

Sample	C		D	
SF BASE™ fluid, bbl (C_{16}/C_{18} Internal Olefin)	0.640		-	
PETROFREE® LV fluid, bbl (Ester)	-		0.640	
Freshwater, bbl	0.085		0.085	
11.6 lb/gal $CaCl_2$ brine, bbl	0.087		0.087	
EZ MUL NT™ emulsifier, lb	7		7	
Lime, lb	5		5	
DRILTREAT™ wetting agent, lb	1		1	
BAROID® weighting agent, lb	243		243	
EXP A1 polymer, lb	12.5		12.5	
After adding EXP A1 polymer, the samples were mixed 30 minutes				
Temperature, °F	40	120	40	120
Plastic Viscosity, cP	52	25	73	31
Yield Point, lb/100 ft^2	27	22	50	39
10 Sec gel, lb/100 ft^2	9	9	30	16
10 Min gel, lb/100 ft^2	10	20	39	29
30 Min gel, lb/100 ft^2	13	23	41	33
Electrical stability, v	-	795	-	1035
HTHP filtrate @ 250°F, ml	-	3.6	-	2.6
FANN® 35 Viscometer Dial Readings				
600 rpm	131	72	196	101
300 rpm	79	47	123	70
200 rpm	60	38	95	57
100 rpm	39	27	67	42
6 rpm	11	10	33	18
3 rpm	9	9	29	16
Tau zero, lb/100 ft^2	7.6	7.4	29.4	13.3
n (flow index)	0.78	0.69	0.84	0.63
K (consistency index)	0.58	0.58	0.51	1.15
GPI	0.1	1.2	0.3	0.8
SBI	0.3	1.7	0.3	1.2

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TABLE 3

(12.1 lb/gal Fluids; 79/21 OWR with 220,000 ppm WPS)

Sample Mark	E		F	
ACCOLADE BASE™ fluid, bbl (Ester/Olefin blend)	0.640		-	
SF BASE™ fluid, bbl (C_{16}/C_{18} Internal Olefin)	-		0.320	
XP-07™ fluid, bbl (C_{13}-C_{15} Paraffin)	-		0.320	
Freshwater, bbl	0.085		0.085	
11.6 lb/gal $CaCl_2$ brine, bbl	0.087		0.087	
EZ MUL NT™ emulsifier, lb	7		7	
Lime, lb	5		5	
DRILTREAT™ wetting agent, lb	1		1	
BAROID® weighting agent, lb	243		243	
EXP A1 polymer, lb	12.5		12.5	
After adding EXP A1 polymer, the samples were mixed 30 minutes:				
Temperature, °F	40	120	40	120
Plastic Viscosity, Cp	75	33	46	23
Yield Point, lb/100 ft^2	74	37	18	20
10 Sec gel, lb/100 ft^2	31	16	7	8
10 Min gel, lb/100 ft^2	36	26	11	18
30 Min gel, lb/100 ft^2	37	29	14	20
Electrical stability, v	-	995	-	767
HTHP filtrate @ 250°F, ml	-	2.8	-	4.4
FANN® 35 Viscometer Dial Readings				
600 rpm	224	103	110	66
300 rpm	149	70	64	43
200 rpm	119	57	47	35
100 rpm	84	42	30	24
6 rpm	35	18	8	9
3 rpm	30	16	7	8
Tau zero, lb/100 ft^2	***26.1***	***13.9***	***6.0***	***6.6***
n (flow index)	0.69	0.66	0.84	0.69
K (consistency index)	1.73	0.97	0.33	0.52
GPI	0.2	0.6	0.6	1.3
SBI	0.4	0.9	0.9	1.7

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[0037] Tables 4, 5, and 6 show the fluid formulations and rheological properties of fluid samples in a further experiment conducted comparing the suspension characteristics imparted by xanthan gum in an aqueous fluid (Sample "0") to the suspension characteristics imparted by organoclays in a synthetic fluid invert emulsion based fluid (Samples "1" and "3") and to the

suspension characteristics imparted by a preferred polymer additive of the present invention, EXP A1, in a synthetic fluid invert emulsion based fluid (Samples "2", "4", and "5"). This data indicates that the fluids of the present invention yield superior results to clays in synthetic fluid invert emulsion fluids and that the fluids of the invention approximate or come close to the effectiveness seen with xanthan in aqueous fluids. Figure 1 further compares these three types of fluids by graphing their respective gel strengths over time. Progressive gel behavior is seen with the xanthan gum and with EXP A1 polymer for the initial hour but not to any significant degree when the GELTONE® II clay additive is used.

TABLE 4
(14.0 lb/gal Fluids; 80/20 OWR with 250,000 ppm WPS)

Sample	0*	1	2
LE BASE™ oil, bbl	–	0.552	0.552
LE MUL™ emulsifier, lb	–	3	3
LE SUPERMUL™ emulsifier, lb	–	7	7
Lime, lb	–	5	5
Freshwater, bbl	–	0.071	0.071
11.6 lb/gal $CaCl_2$ brine, bbl	–	0.088	0.088
Rev Dust, lb	–	20	20
The additives above were blended into a premix.			
GELTONE® II organoclay, lb	–	6	–
EXP A1 polymer, lb	–	–	7.5
The viscosity additive was mixed into aliquots of premix.			
BAROID® weighting agent, lb	–	330	330
After adding weighting agent and mixing for 30 minutes, the samples were hot rolled at 150°F for 16 hrs. Properties measured after hot rolling:			
Temperature, °F	120		
Plastic viscosity, cP	16	25	30
Yield point, lb/100 ft^2	22	16	19
10 sec gel strength, lb/100 ft^2	8	10	6
10 min gel strength, lb/100 ft^2	16	13	9
30 min gel strength, lb/100 ft^2	20	12	11
Electrical stability, v	–	984	707
FANN® 35 viscometer dial readings:			
600 rpm	54	66	79
300 rpm	38	41	49
200 rpm	33	33	38
100 rpm	25	24	26
6 rpm	9	11	8
3 rpm	7	10	6
Tau zero, lb/100 ft^2	***4.2***	***9.9***	***5.3***
n (flow index)	0.51	0.82	0.74
K (consistency index)	1.49	0.21	0.47
GPI	1.0	0.3	0.5
SBI	2.8	0.3	0.7

*Sample "0" was not an oil-based fluid but had an equivalent density to the other samples. Sample "0" consisted of 0.776 bbl freshwater, 1 lb/bbl BARAZAN D PLUS™ xanthan gum viscosifier, 20 lb/bbl Rev Dust, 294 lb/bbl BAROID® weighting agent, and 0.5 lb/bbl BARABUF™ fluid.

TABLE 5
(14.0 lb/gal Fluids; 80/20 OWR with 250,000 ppm WPS)

Sample	**3**	**4**
LE BASE™ oil, bbl	0.552	0.552
LE MUL™ emulsifier, lb	3	3
LE SUPERMUL™ emulsifier, lb	7	7
Lime, lb	5	5
Freshwater, bbl	0.071	0.071
11.6 lb/gal $CaCl_2$ brine, bbl	0.088	0.088
Rev Dust, lb	20	20
GELTONE® II organoclay, lb	6	–
EXP A1 polymer, lb	–	7.5
BAROID® weighting agent, lb	330	330
Observations after static aging:		
Top oil separation, inches	0.4	0.3
Settling apparent? (Yes/No)	Yes, slight	No
Properties measured after mixing for 10 minutes:		
Temperature, °F	120	
Plastic viscosity, cP	23	33
Yield point, lb/100 ft^2	11	16
10 sec gel strength, lb/100 ft^2	7	10
10 min gel strength, lb/100 ft^2	10	16
30 min gel strength, lb/100 ft^2	10	17
Electrical stability, v	855	697
HTHP filtrate @ 250°F/500 psid, mL	13.6	2.8
FANN® 35 viscometer dial readings:		
600 rpm	57	82
300 rpm	34	49
200 rpm	27	39
100 rpm	19	26
6 rpm	8	10
3 rpm	7	9
Tau zero, lb/100 ft^2	***7.1***	***8.6***
n (flow index)	0.85	0.83
K (consistency index)	0.14	0.25
GPI	0.4	0.6
SBI	0.4	0.9

TABLE 6

(14.0 lb/gal Fluid; 80/20 OWR with 250,000 ppm WPS)

Sample	**5**	
XP-07™ oil, bbl	0.552	
LE MUL™ emulsifier, lb	3	
LE SUPERMUL™ emulsifier, lb	7	
Lime, lb	5	
Freshwater, bbl	0.071	
11.6 lb/gal $CaCl_2$ brine, bbl	0.088	
Rev Dust, lb	20	
EXP A1 polymer, lb	10	
BAROID® weighting agent, lb	330	
Properties Measured After Hot Rolling for 16 Hours and Mixing for 10 Minutes:		
Temperature, °F	40	120
Plastic viscosity, cP	85	35
Yield point, lb/100 ft^2	26	28
10 sec gel strength, lb/100 ft^2	8	10
10 min gel strength, lb/100 ft^2	15	21
Electrical stability, v	-	1001
HTHP filtrate @ 250°F/500 psid, mL	1.6	
FANN® 35 viscometer dial readings:		
600 rpm	196	98
300 rpm	111	63
200 rpm	80	50
100 rpm	47	35
6 rpm	9	11
3 rpm	8	10
Tau zero, lb/100 ft^2	***5.4***	***7.4***
n (flow index)	0.85	0.69
K (consistency index)	0.54	0.82
GPI	0.9	1.1
SBI	1.8	1.9

TABLE 7

PETROFREE® SF Drilling Fluids

Sample Mark	B4	B5	B6		B7		B8		
Mud density, lb/gal	12	12	16		16		9.7		
Oil-to-Water Ratio	70/30	70/30	85/15		85/15		75/25		
SF BASE™ fluid, bbl	0.544	0.547	0.520		0.520		0.618		
Freshwater, bbl	0.118	0.111	0.042		0.042		0.100		
GELTONE® II organo-clay, lb	1.5	-	-		-		-		
SUSPENTONE™ additive, lb	1.5	-	-		-		-		
FACTANT™ emulsifier, lb	3.5	3.5	-		4		-		
LE MUL™ emulsifier, lb	-	-	4		-		4		
LE SUPERMUL™ emulsifier, lb	2	2	8		8		8		
11.6 lb/gal $CaCl_2$ brine, bbl	0.146	0.138	0.052		0.052		0.123		
Lime, lb	8	8	5		8		5		
ADAPTA® filtration control agent, lb	-	-	2.5		3.0		-		
BARACARB® 5 additive, lb	-	-	5		5		5		
BAROID® weighting agent, lb	205.2	208.0	440.6		440.6		107		
Rev Dust, lb	20	20	20		20		20		
COLDTROL™ additive, lb	1.0	-	-		-		-		
EXP A1 polymer, lb	-	8	5		4		13		
X-VIS™ additive, lb	-	-	-		0.5		-		
Hot rolled @ 150°F, hr	16	16	16	-	16	-	16	-	
Hot rolled @ 300°F, hr	-	-	-	16	-	-	-	-	
Hot rolled @ 350°F, hr	-	-	-	-	-	16	-	-	
Static aged @ 250°F, hr	-	-	-	-	-	-	-	16	
Samples were mixed 15 minutes on a Multimixer before testing									
Temperature, °F	***120***	***120***	***120***	***120***	***150***	***150***	***120***	***40***	***120***
Plastic viscosity, cP	21	28	46	46	39	38	27	67	30
Yield point, lb/100 ft^2	11	6	22	31	14	9	18	25	24
10 Sec gel, lb/100 ft^2	6	4	8	11	8	7	6	9	11
10 Min gel, lb/100 ft^2	7	7	11	18	18	12	-	14	20
30 Min gel, lb/100 ft^2	7	6	12	21	18	14	-	16	22
Electrical stability, v	234	211	1071	1642	1779	1008	725	-	600
HTHP filtrate @250°F, ml	-	-	-	-	-	-	-	-	1.2
HTHP filtrate @300°F, ml	-	-	5.8	6.8	-	-	-	-	-
HTHP filtrate @350°F, ml	-	-	-	-	6.0	16.8	-	-	-
FANN® 35 dial readings									
600 rpm	53	62	114	123	92	85	72	159	84
300 rpm	32	34	68	77	53	47	45	92	54
200 rpm	25	25	52	60	40	35	35	67	42
100 rpm	16	16	34	39	25	21	23	41	29
6 rpm	6	5	9	13	8	6	7	11	12
3 rpm	5	4	8	11	7	5	6	9	11
Tau zero, lb/100 ft^2	***4.8***	***4.2***	***6.3***	***9.3***	***6.5***	***4.8***	***4.8***	***7.8***	***9.8***
n (flow index)	0.81	0.93	0.78	0.75	0.87	0.91	0.73	0.85	0.76
K (consistency index)	0.18	0.10	0.50	0.68	0.23	0.16	0.44	0.44	0.41
GPI	0.2	0.8	0.4	0.6	1.3	0.7	-	0.6	0.8
SBI	0.5	0.7	0.7	1.0	1.8	1.5	-	0.8	1.0

[0038] In Table 7, Samples "B4" and "B5" investigated the possibility of using FACTANT™ emulsifier as the primary emulsifier for the system. These samples indicated that the product of the invention can be used with other emulsifiers and with fewer components than conventional systems or traditional drilling fluids. Samples "B6" & "B7" were hot rolled at 300 or 350°F. The properties in Sample "B6" were shown to be stable at 300°F, as a small amount of fluid loss control agent--ADAPTA™ filtration control agent--helped provide a low HTHP filtrate before and after hot rolling, indicating good HTHP filtration. The rheological properties and gel strengths for Sample "B7" were stable after hot rolling at 350°F, in spite of the fact that some of the 2-ethylhexyl acrylate had been hydrolyzed because of the high temperature. More fluid loss control agent is needed at 350°F. Sample "B8" was a very simple system, having few components, with EXP A1 polymer effectively alone providing excellent properties to the drilling fluid at 250°F. No settling was observed in Sample "B8" after aging, and only a trace of top oil was apparent. Sample "B8" was also very stable at 250°F. Overall, this data further supports the effectiveness of the invention. All trademarked products in the tables above and EXP A1 are available from Halliburton Energy Services, Inc. in Houston, Texas.

[0039] The foregoing description of the invention is intended to be a description of preferred embodiments. Various changes in the details of the described fluids and methods of use can be made without departing from the intended scope of this invention as defined by the appended claims.